TECHNOLOGY OPTIONS FOR CONTROLLING CO_2 EMISSIONS FROM FOSSIL-FUELLED POWER PLANTS

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Paper Presented at the
Third Annual Conference on Carbon Capture and Sequestration
May 3-6, 2004
Alexandria, VA

ABSTRACT

As one of the largest providers of power generation equipment, turnkey power plants and services in the world, ALSTOM Power Inc. (ALSTOM) is aware of the present scientific concerns regarding greenhouse gas emissions and the role of fossil fuels used in power generation. Our R&D laboratories are conducting various programs aimed at finding options that reduce greenhouse gas (principally CO_2) emissions from both existing and new power plants. This paper summarizes the various CO_2 mitigation technology options for fossil fuel power generation, compares economic performance and explains the status of ALSTOM's developments in these fields. Emphasis is given to technologies for coal and solid fuels.

INTRODUCTION

Global climate change and its potential impacts are among the most debated environmental issues today. The science behind climate change is enormously complicated, but the potential implications of climate change are serious, including ecological, economic, and social. Its prospect is a matter of concern for today's global community. Proposed programs to mitigate the risks of climate change also pose profound potential effects on energy sources used, power technologies, energy supply, the economy, and our society.

Coincidentally, almost every projection on the future of electricity shows a robust increase in demand continuing for decades. The rate will likely be slower in the industrialized regions and faster in the underdeveloped world, but demand is forecast to increase. The major energy sources today are fossil fuels (coal and natural gas), which together account for more than 50% of power generated worldwide. Coal is abundant and is used to produce about one third of global electric power generation. For countries with large domestic coal reserves, such as the USA, China, Germany, and India, for example, the combination of cost and security concerns, make coal's continued widespread use attractive today and into the future.

The impact of carbon reduction policies and concerns is already emerging as demonstrated by the following actions:

- Increased market of gas turbine combined cycle (GTCC), renewables, and other non-coal energy sources.
- Biomass projects: Greenfield, brownfield, and co-firing have emerged as a market in Western Europe.
- Higher efficiency: Supercritical steam cycles are replacing subcritical cycles for both pulverized coal and fluidized bed.
- The development of government incentives to support IGCC in North America.

Hence, ALSTOM is conducting various programs aimed at finding options that reduce greenhouse gas (principally CO_2) emissions from both existing and new fossil-fuelled power plants. Details of these options are addressed from technical, economical, and environmental control standpoints. The techno-economic analysis results are used to rank power plant technologies and CO_2 mitigation options with carbon constraints that vary in degree.

CO_2 MITIGATION OPTIONS

There are a wide range of fossil fuel technology options currently available or being developed to mitigate CO_2 for power generation. These technologies may be applied to the existing fleet (retrofit technologies) and/or to new capacity. Technologies can be grouped within the following three broad categories:

- <u>Efficiency Improvement Technologies</u>:
  Reducing CO_2 emissions and conventional pollutants by improving plant efficiency.
- <u>Fuel Switching Technologies</u>:
  Reducing CO_2 emissions by switching to a less carbon intensive fuel
- <u>CO_2 Capture and Sequestration Technologies</u>:
  Reducing CO_2 emissions through CO_2 capture, or decarbonization and geologic sequestration

Efficiency Improvement Technologies

Improving the plant thermal efficiency will reduce CO_2 emissions and conventional emissions such as SO_2, NOx, and particulate by an amount directly proportional to the efficiency improvement. Modest efficiency gains can be achieved for existing plants through relatively simple measures such as steam turbine upgrades, boiler upgrades, and various other plant upgrades. More complex projects, which provide greater efficiency improvements, are also possible such as repowering to higher temperature and pressure steam conditions, or adding a topping gas turbine cycle and using the existing steam cycle as the bottoming cycle.

Repowering opportunities can provide significant efficiency improvements, but configuration, performance and cost tend to be very site specific. One option is to scrap an existing boiler and replace it with an advanced boiler, such as an oxygen-fired Circulating Fluidized Bed (CFB) or a circulating moving bed (CMB™) boiler with a topping steam turbine thus improving the plant steam conditions.

For new plants, supercritical and ultra-supercritical pulverized coal (PC), CFB, and CMB™ plants are the most cost-effective coal-fired technologies for achieving limited CO_2 reductions (up to 30%). Efficiency improvements have been achieved by operation at higher temperature and pressure steam conditions, and employing improved materials and plant designs. The incremental investment costs for improved steam conditions for new plants tend to be relatively low. ALSTOM has been at the forefront of developing and deploying advanced steam plants over its history and today is actively engaged in material technology advancement and steam plant design efforts to allow for coal power plants with greater than 50% (LHV) net plant efficiency (Bregani, et al., 2002; Kjaer, et al., 2001).

Significant efficiency gains can be achieved with technologies readily available today. ALSTOM is currently offering supercritical PC and CFB plants at steam conditions up to 4,000 psig /1,050 F/1,050 F/1,100 F. The technology exists to offer steam conditions up to 4,500 psig/1,125 F/1,125F/1,170F. Considerable development is ongoing through programs such as EU AD700 and the USA Ultra-Supercritical Consortium to further increase steam conditions up to 5,400 psig/1,300 F/1,325 F/1,325 F.

Fuel Switching Technologies

Another simple method of reducing CO_2 emissions is to switch from coal to a less carbon intensive fuel, such as natural gas, renewable (biomass co-firing), or non-fossil power (e.g., nuclear energy). Fuel switching to natural gas can be achieved by either modification of the boiler to burn gas or by repowering an existing coal-fired plant with a topping natural gas combined cycle (NGCC).

Fuel switching an existing boiler or building new plants to co-fire biomass with coal is another viable means of reducing CO_2 emissions. Biomass fuels are considered CO_2 neutral, because the CO_2 released during combustion from a biomass-derived fuel is recycled back into the next generation of energy crops from which they are derived, thereby creating a closed-loop CO_2 recycle system. Biomass fuels include wood, wood wastes, paper and cardboard, agricultural wastes, and such energy crops as switchgrass, eucalyptus, and willow and poplar trees. Other bio-derived fuels include, for example, municipal solid waste, sewage sludge, and animal waste. This option is particularly active today in Europe where incentives offset the higher cost of the biomass fuel compared to coal. However, the number of units that can be built will be limited by the availability and transportation of the biomass fuels. ALSTOM currently has built over twenty biomass-fired boilers and is currently commissioning 5 new units in Germany.

CO_2 Capture and Sequestration Technologies

There are limited choices available today for the capture and sequestration of CO_2 from fossil fuel power generation systems. However, many technologies are being developed and will be available as the demand for CO_2 capture increases. ALSTOM is closely monitoring this and actively developing some of these technologies, including oxygen firing, CO_2 frosting, CO_2 adsorption, the CO_2 wheel and chemical looping. Most of these technologies can capture over 90% of the CO_2, but typically they are capital intensive, impose a large electric power output reduction, and cause energy efficiency penalties. Table 1 provides a comparison of some of these CO_2 capture technologies.

Table 1: CO_2 Capture Technology Comparison

Plant Technology	CO_2 Capture Technology	ALSTOM's Involvement	CO_2 Composition in Flue Gas, %	CO_2 Capture Efficiency, %	Energy Penalty, %	Investment Cost Increase, $/kW	CO2 Avoided Cost, $/ton	COE Increase, Cents/kWh	CO2 Capture System's Technical Status
NGCC	MEA	No	3.5	90+	22	412	57	2.4	Commercial
IGCC	Double Selxol	No	15 (in fuel gas)	90+	21	353	16	2.5	Commercial
PC or CFB	MEA	No	13.5	90+	41	1602	63	6.2	Commercial
	Oxyfuel	Yes	80	90+	29	1042	46	4.4	ASU& Gas Processing Systems are commercial
	CO_2 Wheel	Yes	13.5	63		278	16	1.5	Conceptual
	Frosting	Yes	13.5	90+	34	1190	46	4.5	Conceptual
	50% Biomass Co-Firing	Yes	13.5	50	Minimal	44	15	0.7	Commercial
CLC	N/A	Yes	80	90+	13	543	14	1.8	Conceptual

CO_2 capture technologies can be grouped into the following three categories:

- Oxygen Combustion - Oxygen firing to produce a concentrated CO_2 flue gas stream.
- Tail end CO_2 Capture - Technologies that capture the CO_2 after it has already been generated in the boiler.
- De-carbonization - Technologies that remove or capture the CO_2 prior to or during the combustion process.

Oxygen Combustion

Conventional coal fired plants, use air as the oxidant and generate a dilute CO_2 exhaust gas that is almost 80% nitrogen. Hence, the CO_2 separation equipment is quite expensive and energy intensive partly because the entire flue gas volume must be processed.

By firing with nearly pure oxygen, atmospheric nitrogen is not introduced into the products of combustion and a concentrated CO_2 flue gas stream is produced. The CO_2 gas stream can then be purified, and compressed more cost effectively than a dilute CO_2 stream from conventional combustion processes. Oxygen fired plants are still quite capital intensive and energy intensive because of the power required by the cryogenic air separation unit (ASU), which is needed to separate oxygen from the air. In the future, advanced oxygen fired plants using oxygen transport membrane (OTM) processes may significantly reduce these costs.

Similarly, advanced oxygen fired plants using a chemical looping combustion process look very promising with respect to both efficiency and economics. Both OTM and chemical looping will require a long development process before they will be ready for commercial application. Examples of these three methods of oxygen firing are briefly summarized below.

- Oxygen Fired Boiler

ALSTOM is actively developing an O_2 fired CFB with co-funding by the US DOE. An oxygen-fired CFB is supplied oxygen from a Cryogenic Air Separation Unit (ASU). The boiler island provides a concentrated CO_2 flue gas product stream to the gas processing system. There, the CO_2 is captured, purified, and compressed for subsequent sequestration. This results in cost savings from a smaller boiler island, compared to an air-fired CFB and cost savings on gas processing system equipment compared to amine-based CO_2 scrubbing systems. An oxygen-fired CFB has an advantage over other boiler concepts in that it can control combustion temperature by recycling cooled solids and it is fuel flexible, inherent attributes of CFB boilers. It uses readily available commercial technologies, including oxygen production with an air separation unit and gas processing systems to produce enhanced oil recovery (EOR) quality CO_2 product. A near term opportunity for O_2-fired CFB's is for EOR applications, where the CO_2 gas can be pumped directly underground. Phase I was completed last year, which included preliminary techno-economic analysis of an oxygen fired 210-MWe plant, under both Greenfield and retrofit assumptions. ALSTOM is currently in the process of executing a pilot-scale testing to evaluate the concept in a 9.9 MM-Btu/h facility. Tests include two coals and one petcoke and combustion in O_2/CO_2 mixtures containing up to 70% O_2 by volume. The next steps after this program will be to design a commercial plant for demonstration and then pursue the demonstration of Oxygen-fired CFB for EOR.

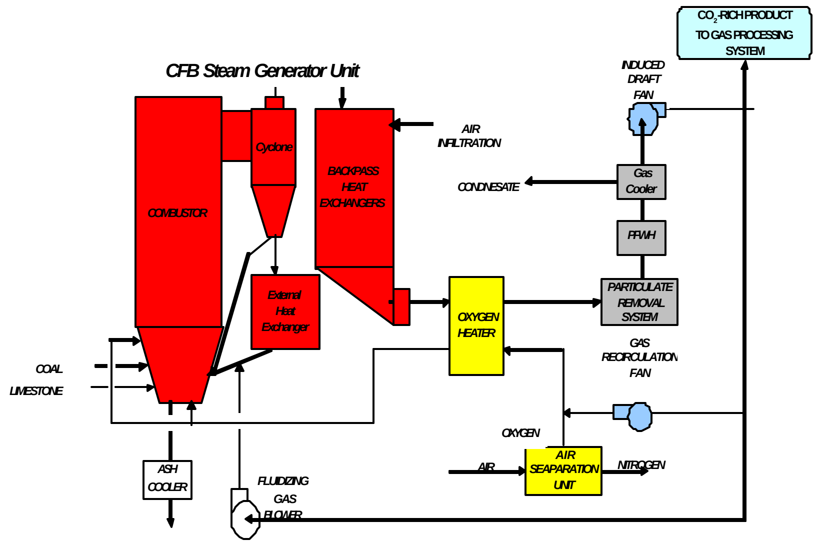

Figure 1: Oxygen Fired CFB

- Oxygen Transport Membrane

An oxygen membrane (OTM) is a more efficient method for oxygen production as compared to a cryogenic ASU, but requires high temperature air for the membranes to operate. This requires integration with the power cycle. ALSTOM has conceptualized OTM integration concepts with CFB and CMB™ processes. Several companies are developing oxygen membrane technology, but it is expected to be 5-10 years before they become cost-effective and practical at scales required for electric power generation (Prasad, et al., 2002).

- Chemical Looping Combustion (CLC)

Chemical Looping Combustion is indirect combustion of coal with oxygen via chemical looping oxygen carrier solids.

A major advantage associated with chemical looping is that oxygen is supplied to the combustion process without the large efficiency penalty or investment cost associated with a cryogenic type Air

Separation Unit (ASU) or Oxygen Transport Membrane (OTM). ALSTOM is in the early states of development of this technology with support from the U.S. DOE. ALSTOM is also participating in chemical looping system developments in collaboration with EU/ADEME/Chalmers University (Kronberger, et al., 2004)

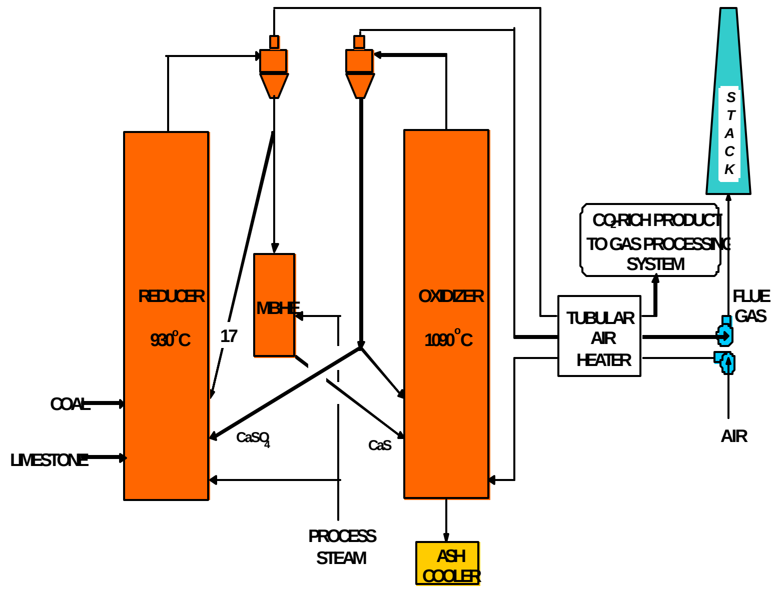

Figure 2: Chemical Looping Combustion

Tail end CO_2 Capture

Tail end CO_2 capture includes a range of technologies that capture CO_2 after it has already been generated in the boiler or combustion turbine. It includes technologies such as solvents (amines) for scrubbing, CO_2 wheel concept, and refrigeration based, such as the CO_2 frosting concept. The gas inlet to the CO_2 capture system should be usually ultra cleaned for other substances such as SO_2, and mercury. ALSTOM Environmental Control Systems has the knowledge and experience for supplying such kinds of systems. The following section briefly summarizes some of the tail end CO_2 capture technologies.

- Monoethanolamine (MEA)

A monoethanolamine (MEA) based absorption-stripping process can be used to capture CO_2 from the flue gases leaving a NGCC or coal-fired boiler, followed by a CO_2 compression and liquefaction system. The MEA process is commercial, but in its current form, it is very energy intensive, consuming more than thirty percent of a power plant's gross output (Bozzuto et al., 2001). ALSTOM has built the only two coal power plants in the world that employ this technology, which in these cases was to produce industrial and food grade CO_2 for neighboring industries (e.g., Barchas, et al., 1992). Further improvement in solvents, thermal integration, and application of membrane technologies is expected to improve amino-based CO_2 capture systems.

- CO_2 Frosting Concept

This process captures CO_2 from flue gas generated from a boiler or NGCC by the principle of low temperature refrigeration (or frosting). This process is being developed at the Ecole de Mines de Paris, France, with support from ALSTOM Environmental Control Systems (Clodic & Younes, 2001).

- CO_2 Adsorption with Solids

CO_2 separation from a flue gas stream of a boiler or gas turbine through adsorption on a solid material is very much dependent on the properties and capacity of the adsorbent. Developing a solid material for CO_2 capture is focused in a research program conducted by the University of Oslo and SINTEF Materials and Chemistry (Oslo), in co-operation with ALSTOM Environmental Control Systems, among other industrial partners.

- CO_2 Wheel Concept

The concept uses a regenerative air-heater-like device with solid absorbent material for the capture of CO_2 from the exhaust gas exiting a boiler or NGCC, followed by a CO_2 compression and liquefaction system. This is a relatively low cost CO_2 capture technology, although current projections limit it to capturing only about 60% of the CO_2 in the flue gas. This technology is being developed by Toshiba in Japan, with support from ALSTOM (Shimomura, 2003).

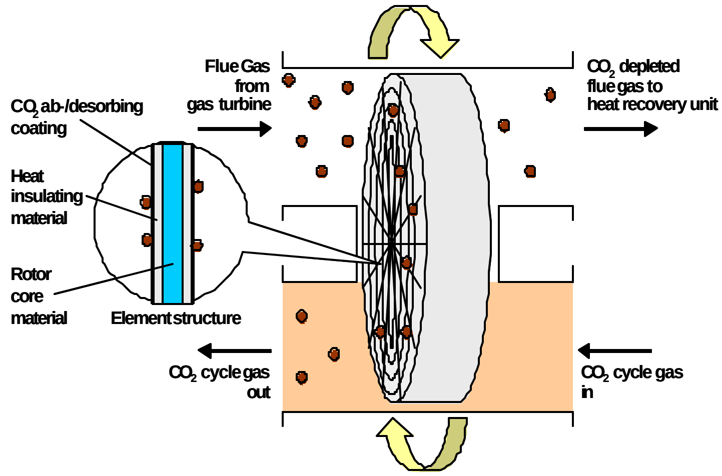

Figure 3: CO_2 Wheel Schematic

<u>De-carbonization</u>

De-carbonization implies technologies that remove or capture the CO_2 prior to or during the combustion process. It includes technologies such as Integrated Gasification Combined cycle (IGCC), carbonate regeneration cycles and chemical looping gasification. These technologies are briefly summarized below.

- IGCC with CO_2 Capture

Gasification is a process where coal or other carbonaceous feed stocks are exposed to steam and controlled amounts of air or oxygen at high temperature and pressure to form a fuel gas or syngas, which is comprised of primarily CO and H_2. This syngas is cleaned and then can be utilized in a variety of ways, although IGCC implies the use of the syngas for power generation in a gas turbine combined cycle (GTCC). The syngas can be shifted ($CO + H_2O \rightarrow H_2 + CO_2$) to allow the capture of CO_2 by absorption/stripping processes or in the frosting or membrane-based processes. A number of absorption processes are available that remove CO_2 under pressures typically found in IGCC processes. The double Selexol process (using dimethylether of polyethylene glycol solvents) is one such process that can be used to capture CO_2 from an IGCC plant.

The shift process increases the concentration of H_2 in the fuel gas. An entirely new gas turbine technology must be developed to enable hydrogen-enriched combustion. It is considered a scientific challenge to improve the combustion technology with hydrogen-enriched synthesis gas because ultra-low emissions must be compromised with stability. This problem is of such significance that ALSTOM and Siemens, have decided to join efforts with two experienced R&D providers in this field. This effort will generate fundamental knowledge on the combustion of H_2-rich fuels in gas turbines, and direct this knowledge to the development of gas turbine combustors. The burners must be compatible with established industrial standards governing emissions, safety, operability, fuel flexibility, reliability and durability. Two different design concepts (premixed and diffusion burners) will be included (Pfeffer, 2004).

Additionally, hydrogen from gasifiers can be provided for other uses including hydrogen-powered automobiles and power generating fuel cells. The syngas can also be used as a chemical building block for petrochemical products, such as ammonia, methanol, fertilizers and liquid fuels for transportation. Gasification is widely used today in the petrochemical industry but further improvements are needed in reducing capital costs and improving availability to make IGCC power plants an economical option for power generation.

- Regenerative Carbonate Process

A regenerative carbonate cycle has been envisioned by ALSTOM, which uses a recirculating stream of lime to capture CO_2 as calcium carbonate. Energy is then supplied to a calciner to recover the CO_2 while regenerating the lime. This process is less capital and energy intensive than many other current solutions because it utilizes air firing and also the carbonate regeneration reaction occurs at higher temperatures than steam cycle temperatures. Thus all of the energy rejected from the carbonate regeneration process is recovered in the steam such that there is no thermodynamic efficiency penalty associated with CO_2 capture for this process. Nearly pure CO_2 is removed continuously from the calciner within the boiler island. This CO_2 stream is then cooled and ready for compression and liquefaction. This process can be integrated with an air-fired CFB or CMB™ boiler, which can supply high temperature solids as the energy source for the calcination reaction allowing regeneration of the calcium and recovery of the CO_2. ALSTOM is currently in the very early stages of developing this technology.

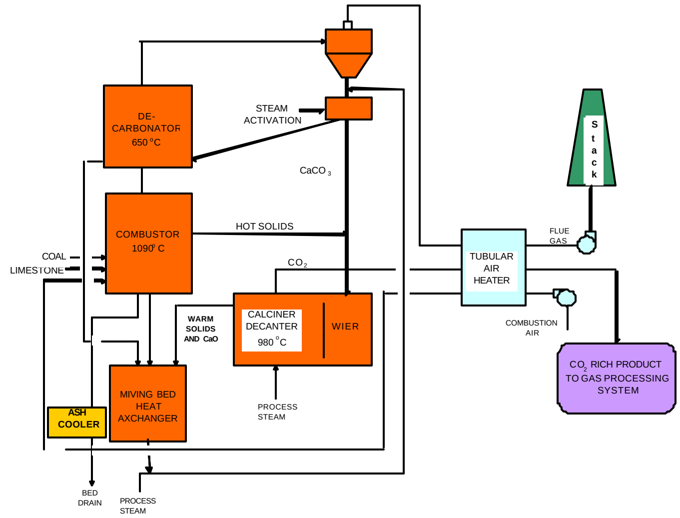

Figure 4: Regenerative Carbonate Process

- Chemical Looping Gasification (CLG)

Chemical-looping gasification, as envisioned by ALSTOM, uses two primary chemical loops in the process to produce both a relatively pure CO_2 stream and a medium Btu gas (more than 90% hydrogen). The oxygen used in the gasification process is provided by a solid oxygen carrier. The continuously looping solid oxygen-carrier is first used to partially oxidize the fuel into primarily H_2 and CO. Secondly, the CO is shifted to CO_2 and a regenerative carbonate cycle is used for CO_2 capture. Chemical looping is an advanced technology under early stages of development by ALSTOM. This very promising technology has the potential to have the lowest capital and operating costs of all advanced CO_2 capture technologies considered and offers a very attractive approach for reducing CO_2 emissions. This is because the oxygen is supplied to the gasification process without the large efficiency penalty associated with a

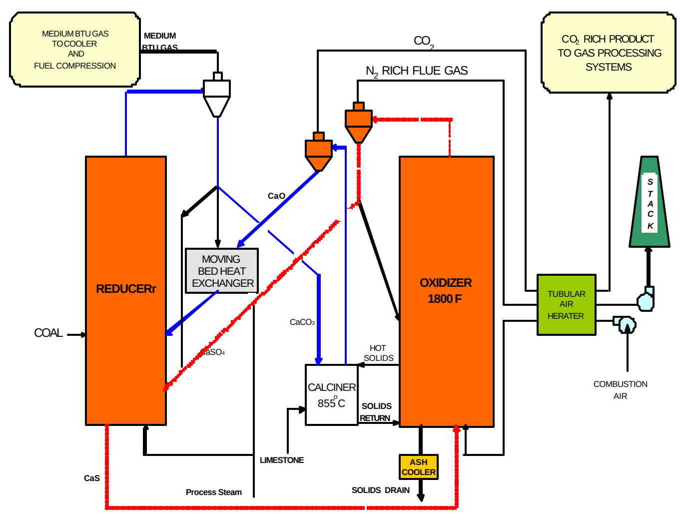

Figure 5: Chemical Looping Gasification

cryogenic type air separation unit or oxygen transport membrane and the carbon dioxide separation is at high temperature. It also avoids the large investment cost associated with the ASU or OTM.

ECONOMIC COMPARISONS

This section provides evaluations of the CO_2 mitigation technology options available for both retrofits of existing power generating units and for new capacity (both present day and future). The results are based on simple economic analysis of a wide variety of available technologies and were based on economic parameters typical of base loaded units. This analysis was limited to base loaded units because they would likely be the first units converted or built (retrofit and/or new capacity) for mitigation of CO_2 and they would likely provide a better return on investment than intermediate or peak load units. Further into the future, after all or most of the base loaded capacity is converted to CO_2 capture, intermediate load and peak load units (typically natural gas fired capacity) might follow depending on economics and other driving factors. Both coal and natural gas have been and are projected to continue to be major players in the power generation sector, coal for base load applications and gas for intermediate and peak load.

The parameters of merit used to evaluate electric power production technologies from a purely economic standpoint are listed below:

- Variable cost of generation
- Equipment investment costs
- Cost of electricity (COE)

The technology options of choice for base load power generation today generally must have low variable cost of generation, thus allowing the units to dispatch to the highest capacity factors. In addition to low variable cost of generation, they also have relatively low specific investment costs ($/kW). This combination of low variable cost of generation and low investment costs maximizes the return on investment and provides a low cost of electricity. These two preferred characteristics will exist whether or not there are carbon constraints.

Variable cost of generation, commonly quantified in units of Cents/kWh, are comprised of three components:

- Fuel costs
- Variable operating and maintenance (O & M) costs
- CO_2 allowance price (in a cap and trade regulatory system)

Several comprehensive economic evaluations comparing the various power plant configurations were utilized. These comparisons were developed for numerous types of fossil-fuel fired power plants including PC, CFB, CMB™, IGCC, NGCC, and other advanced technologies. The economics of new capacity as well as retrofit/repowering of existing coal-fired plants was investigated. The study scope considered technology for today's plants as well as power plants for the future and included cases with and without CO_2 capture. The study made use of mostly existing information (Performance, Investment costs, and O&M costs) from several detailed evaluations (Marion, et al., 2003; Holt, 2000; Palkes, et al., 2004; and Bozzuto, et al., 2001). Various economic parameters used in the original studies were then adjusted in order to put all the economic results (variable cost of generation and cost of electricity) on an equivalent basis. Economic parameters used for this study are listed below:

• Coal Cost	1.25 ($/MM-Btu)
• Natural Gas Cost	Range: 3.0-7.0 ($/MM-Btu)
• CO_2 credit allowance price	Range: 0-50 ($/ton of CO_2)
• Capacity Factor	80% - 7,008 (hrs/yr)
• Performance (thermal efficiency)	Taken from referenced studies
• Investment Costs ($/kW)	Taken from referenced studies
• Annual Capital Charge Rate	Taken from referenced studies

Additionally, all costs shown and economic evaluations provided in this paper are for power generation and CO_2 capture only. Additional costs will be incurred for offsite piping and sequestration of the CO_2. Cases with CO_2 capture only include equipment necessary for capture, purification, and compression of the CO_2 to a sequestration ready state.

For this study, a CO_2 cap and trade system was assumed. An allowance price range of from 0 – 50 $/ton CO_2 for CO_2 credits was used as a sensitivity variable in this study. For existing units under a "cap and trade" system such as was assumed for this analysis, two possible scenarios can exist.

- **Scenario-1**: The cap is fully used and the utility must buy CO_2 credits at the allowance price.
- **Scenario-2**: The cap is not fully used and the utility can sell CO_2 credits at the allowance price.

In Scenario 2 the selling of CO_2 credits is based on the difference between the CO_2 emission of the retrofitted unit and the CO_2 emission of the existing unmodified unit. Because for existing units there are two possible scenarios (depending on buying or selling CO_2 credits), the economic results for variable cost of generation and cost of electricity are presented as two sets of graphs, one assuming buying and one assuming selling of CO_2 credits. For new units only Scenario-1 applies since new units are not allocated any CO_2 credits and would be required to buy credits at the prevailing allowance price.

CO_2 Credit Value:
In this analysis, the term "CO_2 Allowance Price" is used as a generic term representing the price for CO_2 credits which can be bought or sold. There are several forms of regulatory actions that could be used to impose a CO_2 emission impact on electricity production. These could include a cap and trade system, a CO_2 tax, subsidies for alternate generation, etc. However, the effect of all of these factors is included in the cap and trade system, which was used in this study.

Various studies have shown that initial values of CO_2 allowance prices will be relatively low. Therefore a range from 0-$50/ton CO_2 was selected for the analyses in this study.

Retrofit Technologies for CO_2 Mitigation for Existing Units

Currently, global electric power generating capacity is about 3,900 GWe. The potential CO_2 mitigation retrofit market consists of a global capacity as distributed below:

- ~1,300 GWe of existing coal combustion plants (PC and CFB)
- ~324 GWe of existing natural gas combined cycle (NGCC)
- ~320 GWe of natural gas simple cycle (NGSC)

- ~ 371 GWe of natural gas fired boilers
- ~ 2 GWe of existing coal IGCC

The remaining capacity (~1,580 GWe) includes nuclear, hydroelectric, oil fired boilers, and others (wind, solar, biomass, etc.). As such, the prevalent CO_2 mitigation retrofit market is for coal combustion and/or NGCC/NGSC or natural gas fired boilers.

As described previously, much of the natural gas capacity is used for intermediate and peaking service. Given the choice to retrofit either gas fired capacity or coal combustion units, the first choice would be to retrofit those units that after modification could be dispatched to the highest capacity factors, (i.e., base loaded coal combustion units) to maximize return on investment. IGCC units would also represent a good choice to retrofit, although there are very few of these units in service today. Using this premise, all retrofit options in this study are evaluated relative to a baseline of an existing subcritical coal fired power plant (PC or CFB). The retrofit options investigated here fall into three basic categories: 1.) Retrofits for fuel switching, 2.) Retrofits for efficiency improvements, and 3.) Retrofits for CO_2 capture.

The fuel switching retrofits investigated include:

- Switching to natural gas firing in the existing coal fired boiler
- Repowering the existing steam cycle with NGCC w/o CO_2 capture
- Subcritical PC or CFB with 50% biomass firing

The efficiency improvement retrofits investigated include:

- Hybrid cycle repowering (Weinstein, 2003)
- Ultra-supercritical repowering with CMB™ boilers (Palkes, et. Al., 2004)

The CO_2 capture retrofit options investigated include the following technologies:

- NGCC repowering (for a range of natural gas costs) with amine scrubbing
- IGCC repowering with double Selexol
- Subcritical PC or CFB with amine scrubbing
- Subcritical PC or CFB with oxygen firing
- Subcritical PC or CFB with CO_2 frosting/anti-sublimation
- Subcritical PC or CFB with CO_2 Wheel
- Chemical looping combustion with a topping steam turbine repowering.

The left side graphs of Figure 6 and Figure 7 show variable cost of generation (fuel + CO_2 allowance price) for the various retrofit options listed above as a function of the CO_2 allowance price level. Figure 6 assumes Scenario-1 where the utility is buying CO_2 credits and Figure 7 assumes Scenario-2 where the utility is selling CO_2 credits. The existing plant with no modifications is also shown in these figures for comparison.

These figures clearly show that even at gas prices as low as 3.0 \$/MM-Btu, variable cost of generation for the NGCC repowering option are so high that it would only dispatch to very low capacity factors. At low CO_2 allowance prices (<~5.0 \$/ton), biomass co-firing variable cost of generation is slightly better than those of all other near-term coal-fired capture options considered. At higher CO_2 allowance prices (> ~5.0 $/ton), biomass is inferior to the other near-term coal-fired CO_2 capture options. The CO_2 Wheel, which is a medium term option, suffers a disadvantage in variable cost of generation due to the use of natural gas firing for sorbent regeneration in the system. Chemical Looping Combustion (CLC), combined with an ultra-supercritical topping steam cycle produces the lowest variable cost of generation. This is a long term development option.

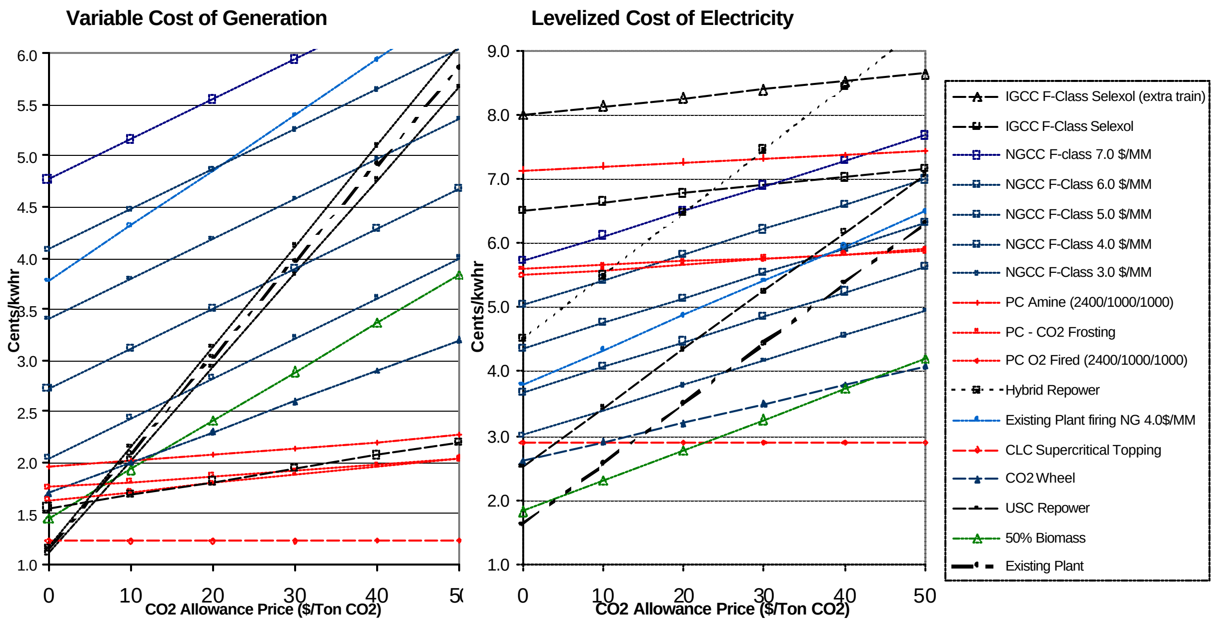

Figure 6: Variable Cost of Generation and Cost of Electricity for Retrofit Technologies (buying credits)

- Variable cost of generation determines dispatch order
- Coal dispatches over gas (either NGCC or fuel switch)
- Coal w/CO_2 capture dispatches over non-capture when CO_2 allowance price > 10 $/ton CO_2
- IGCC dispatches as well as all coal cases except chemical looping

- Existing plant has lowest COE for CO_2 allowance price < 10-20 $/ton CO_2
- Biomass co-firing , CO_2 wheel, Chemical looping repowering lowest COE for CO_2 allowance price > 20 $/ton
- IGCC among worst cases

The right-hand side of Figure 6and Figure 7 show the levelized cost of electricity, for retrofit CO_2 capture technologies. Figure 6 (Scenario-1) is where the utility is buying CO_2 credits and Figure 7 (Scenario-2) is where the utility is selling CO_2 credits. The cost of electricity shown in these COE figures includes the total fuel cost, the total CO_2 allowance cost, O&M cost, and the incremental cost for capital associated with the retrofit. These COE results can be used in combination with the variable cost of generation to determine the retrofit technologies of choice as described below.

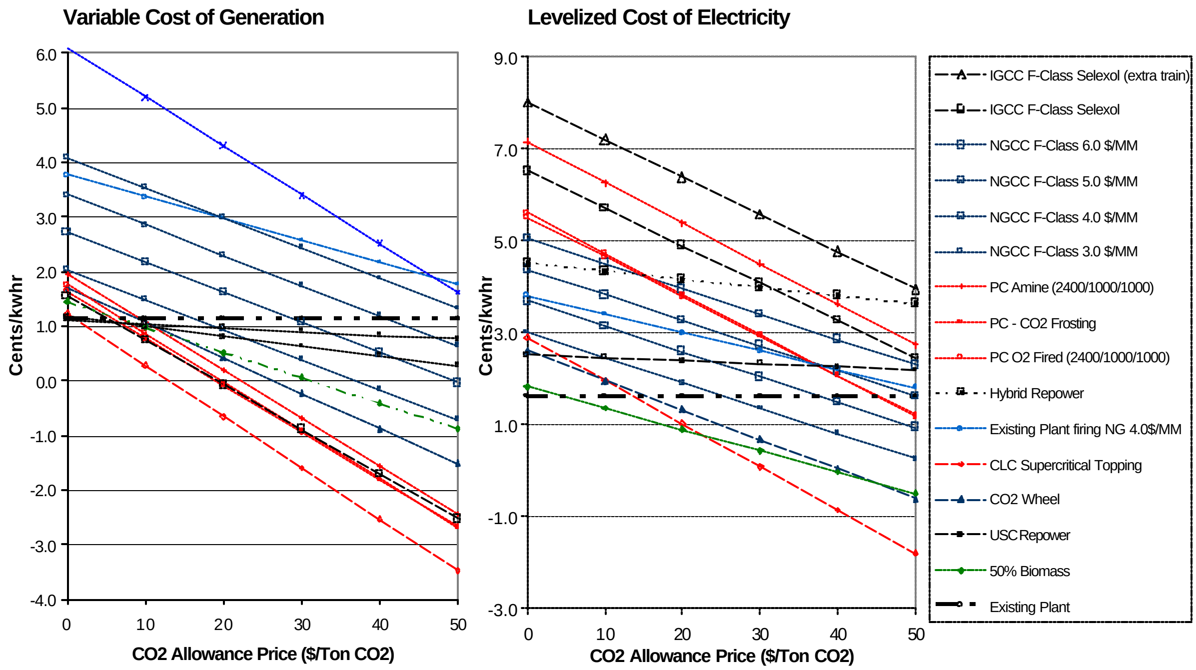

Figure 7: Variable Cost of Generation and Cost of Electricity for Retrofit Technologies (selling credits)

Retrofit Conclusions:

The conclusions reached from Scenario-1 or Scenario-2 are the same. The retrofit technology option of choice would first be biomass co-firing or efficiency improvements for low to medium CO_2 allowance prices 5-20 $/ton CO_2 (note; the available quantities of biomass are very limited). As allowance price levels increase the picture changes quickly. In an environment with CO_2 allowance price levels >~5.0 $/ton of CO_2, the most promising near term retrofit technologies for coal combustion (PC or CFB) are O_2 firing and CO_2 frosting. In the longer term, Chemical Looping Combustion (CLC) repowering is projected to be superior. The variable cost of generation for the CO_2 wheel system would be very competitive with or superior to the other coal combustion retrofit options at low-to-moderate CO_2 allowance prices if the quantity of gas firing used in the system could be reduced or eliminated. Additionally, the CO_2 wheel system could be an attractive technology at higher CO_2 allowance prices as well, if it could be adapted to capture a greater percentage of CO_2 without increasing investment or operating costs too much.

New Capacity Options for CO_2 Mitigation

This section discusses the economic comparison of a number of present day and future technologies, with and without CO_2 capture for new plants. The non-CO_2 capture options were included because one of the options is for utilities to install new capacity without CO_2 capture, but with a provision to install CO_2 capture equipment in the future, if warranted. While the market forecast for new capacity is beyond the scope of this evaluation, it is interesting to consider that if existing units are retrofit to capture CO_2, significant capacity reductions will occur and new capacity will be necessary.

For new units under a "cap and trade" regulatory system assumed for this analysis, the utility must buy CO_2 credits at the allowance price. The economic analysis which follows assumes this scenario and the allowance price for CO_2 credits is varied from 0-50 $/ton of CO_2 as a sensitivity variable.

New Capacity - Present Day Technologies without CO_2 Capture

The present day technologies without CO_2 capture considered in this analysis include the following:

- NGCC with F-class Gas Turbines
- IGCC with F-class Gas Turbines [with and without extra gasifier train. It should be noted that an extra train is currently required to provide acceptable availability for IGCC plants (Wilhelm, 2003)]
- PC or CFB, subcritical (2,400 psig/1,000 F/1,000 F) and supercritical (3,625 psig/1,049 F/1,112F)
- PC with 50% biomass co-firing subcritical (2,400 psig/1,000F/1,000F)

The left side of Figure 8 shows variable cost of generation (fuel + CO_2 credit allowance price) for the present day options without CO_2 capture as a function of the CO_2 allowance price level. The NGCC option is shown for a range of fuel costs. Figure 8 shows that, even at gas prices as low as 3.0 $/MM-Btu and CO_2 allowance price levels of up to 20 $/ton, variable cost of generation are high so that the NGCC would only dispatch to very low capacity factors. Additionally, the variable cost of generation for IGCC and PC or CFB are similar, and better than NGCC at CO_2 allowance price levels of up to 20 $/ton. Above 20 $/ton CO_2 allowance price level, NGCC variable cost of generation is superior to coal-based technologies without capture, as long as the gas cost is equal to or less than 3.0 $/MM-Btu. Similarly, above 30 $/ton CO_2 allowance price level, NGCC variable cost of generation is superior to coal-based technologies without capture, as long as the gas cost is equal to or less than 4.0 $/MM-Btu. At higher CO_2 allowance price levels, higher gas prices also become favorable. Today's prices of natural gas are more than 4.0 $/MM-Btu. Above $10/ton allowance price level, however, biomass dispatches the best.

The right side of Figure 8 shows the levelized cost of electricity, for these technologies without CO_2 capture. These COE results can be used in combination with the variable cost of generation results to determine the most favorable technologies. The most favorable technology option would first be supercritical PC or CFB followed closely by subcritical PC or CFB and then IGCC for CO_2 allowance prices less than 20 $/ton. Although the investment cost of the NGCC is very low, this technology is not of first choice, because high gas costs would prevent it from dispatching to high enough capacity factors. At CO_2 allowance prices greater than 20 $/ton NGCC becomes more attractive. Biomass co-firing looks better than coal firing at CO_2 allowance price levels > $15/ton CO_2.

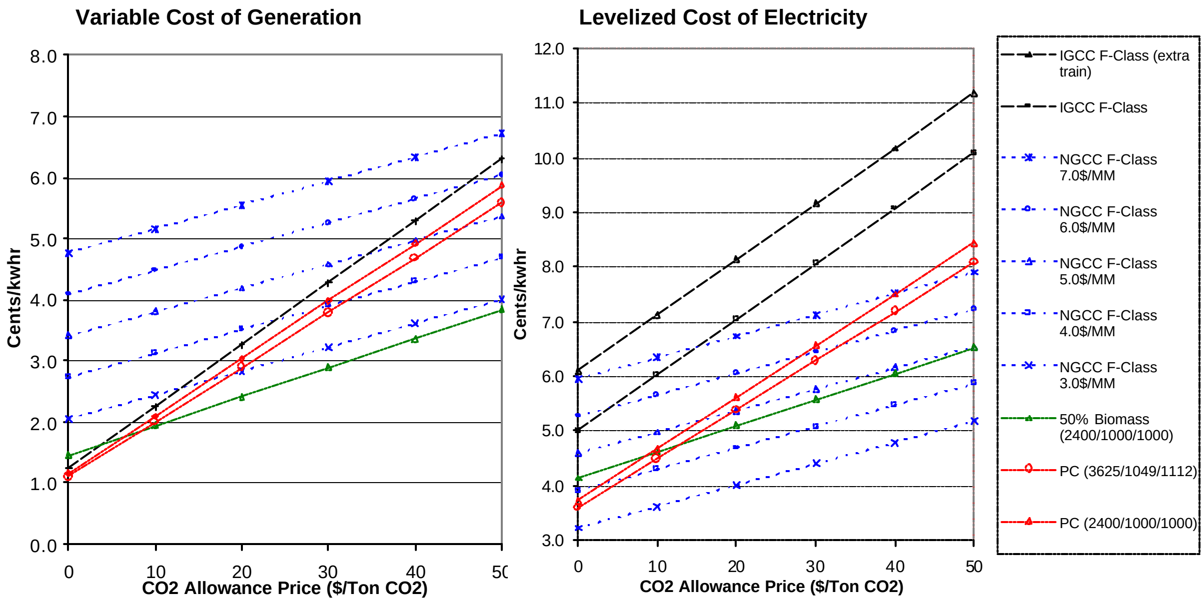

Figure 8: Variable Cost of Generation and Cost of Electricity for Present Day Technologies without CO_2 Capture (buying credits)

- Variable cost of generation determines dispatch order
- Coal (steam and IGCC) dispatches before NGCC until CO_2 allowance price > 30-40 \$/ton CO_2 with current gas prices
- 50% Biomass co-firing dispatches before coal when CO_2 allowance price > 10 \$/ton CO_2

- NGCC has lower COE than coal when CO_2 allowance price > 10 \$/ton CO_2 and gas < 4 \$/10^6 Btu
- Coal-fired steam plants have lower COE than IGCC
- 50% Biomass co-firing has lower COE than coal when CO_2 allowance price > 15 \$/ton CO_2 and has about the same COE as NGCC at 4.5 \$/MM-Btu

New Capacity - Present Day Technologies with CO_2 Capture

One of the options for utilities is to install new capacity with CO_2 capture. The present day technologies evaluated with CO_2 capture included:

- NGCC with MEA scrubbing and F-class Gas Turbines (and at various gas prices)
- IGCC with double Selexol and F-class Gas Turbines (with and without extra gasifier train)
- Subcritical (2,400 psig/1,000 F/1,000 F) and supercritical (3,625 psig/1,049 F/1,112 F) PC or CFB with oxygen firing
- Supercritical (3,625 psig/1,049 F/1,112 F) PC or CFB with MEA scrubbing
- Subcritical (2,400 psig/1,000 F/1,000 F) PC or CFB with 50% Biomass Co-Firing (biomass cost = 1.5 x coal cost).

The left side of Figure 9 shows variable cost of generation (fuel + CO_2 credit allowance price) for the present day options with CO_2 capture as a function of the CO_2 allowance price level. The NGCC option is shown for a range of fuel costs. Figure 9 shows that, even at gas prices as low as 3.0 \$/MM-Btu for all CO_2 allowance price levels investigated, variable cost of generation is high so that the NGCC would only dispatch to very low capacity factors. Additionally, the variable cost of generation for IGCC and PC or CFB is similar, and better than NGCC at all CO_2 allowance price levels. Oxygen firing and PC with MEA scrubbing have similar and just slightly higher dispatch costs than PC and/or CFB.

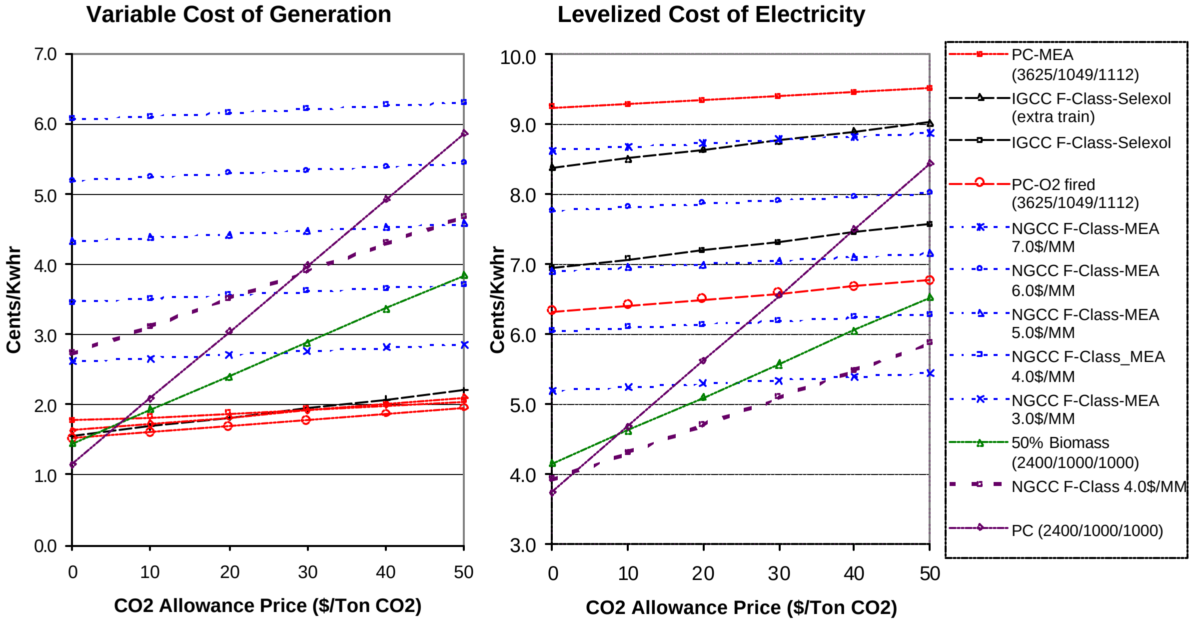

Figure 9: Variable Cost of Generation and Cost of Electricity for Present Day Technologies with CO_2 Capture (buying credits)

- Variable cost of generation determines dispatch order
- Coal w/o capture dispatch before NGCC w/o capture when CO_2 allowance price < $30/ton CO_2
- Coal with CO_2 capture dispatches before all NGCC cases at all CO_2 allowance price levels
- No dispatch difference for coal IGCC or PC-O_2 fired or PC-MEA
- 50% Biomass co-firing dispatches before coal with capture when CO_2 allowance price <$5/ton CO_2

- Non-capture coal case has lower COE than all coal capture cases until CO_2 allowance price > 30-40 $/ton
- Non-capture NGCC case lowest COE vs. all other cases 0 < CO_2 allowance price < 50 $/ton CO_2
- 50% Biomass co-firing has lower COE than coal with capture when CO_2 allowance price < 50 $/ton CO_2 and has lower COE than NGCC with capture at 4.5 $/MM-Btu at CO_2 allowance price < 50 $/ton CO_2

The right side of Figure 9 shows the cost of electricity for these technologies with CO_2 capture. The favored present day technology option with CO_2 capture would first be Biomass co-firing, then O_2 fired supercritical PC or CFB followed closely by O_2 fired subcritical PC or CFB, and then IGCC F-class with Selexol. Although the investment cost of the NGCC F-class with MEA scrubbing is very low relative to the coal-based technologies, this technology is not of first choice for base load applications, because high gas costs would prevent it from dispatching to high enough capacity factors.

New Capacity - Future Technologies without CO_2 Capture

The future technologies without capture considered include:

- NGCC with H-class Gas Turbines
- IGCC with H-class Gas Turbines (with and without extra gasifier train)
- CBM™ Ultra-supercritical boilers (5,075 psig/1,292 F/1,328 F)
- PC or CFB Ultra-supercritical (5,075 psig/1,292 F/1,328 F)
- 50% Biomass co-firing PC or CFB Ultra-supercritical boilers (5,075 psig/1,292 F/1,328 F)

The left side of Figure 10 shows variable cost of generation (fuel + CO_2 allowance price) for future options without CO_2 capture as a function of the CO_2 allowance price level. The NGCC option is shown for a range of fuel costs. Figure 10 clearly shows that, even at gas prices as low as 3.0 $/MM-Btu and CO_2 allowance price levels of up to 20 $/ton, variable cost of generation are so high that the NGCC would only dispatch to very low capacity factors. Additionally, the variable cost of generation for IGCC and PC or CFB are nearly identical, and better than NGCC at CO_2 allowance price levels of up to 20 $/ton. Above 20 $/ton allowance price level, NGCC variable cost of generation is superior to coal-based technologies without capture, as long as the gas cost is equal to or less than 3.0 $/MM-Btu. At higher CO_2 allowance price levels, higher gas prices also become favorable. Biomass dispatch looks very good at CO_2 allowance price levels > $5/ton CO_2.

The right side of Figure 10 shows the levelized cost of electricity for these future technologies without capture. These COE results can be used in combination with the variable cost of generation results to determine the most favorable technologies. The future technology option of choice without CO_2 capture would first be CMB™ ultra-supercritical plants, followed by PC or CFB ultra-supercritical, and then IGCC for CO_2 allowance prices less than 20 $/ton. Although the investment cost of the NGCC is very low, this technology is not of first choice, because high gas costs would prevent it from dispatching to high enough capacity factors. Above 20 $/ton allowance price level, NGCC starts to become more favorable. Biomass co-firing looks best above allowance price levels of about 15 $/ton CO_2.

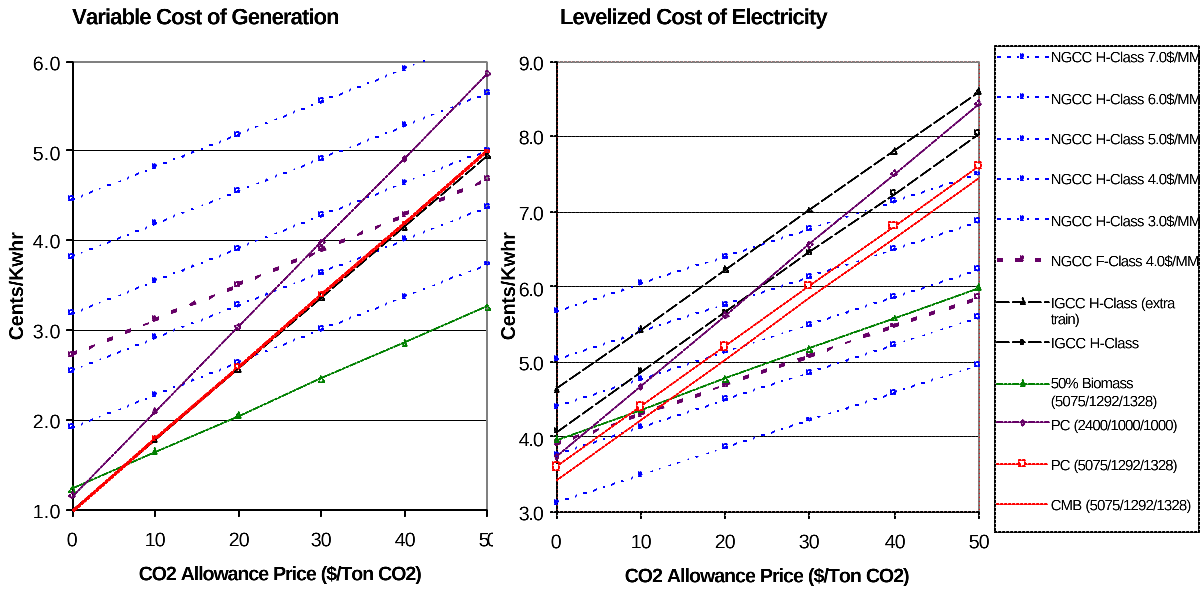

Figure 10: Variable Cost of Generation and Cost of Electricity for Future Technologies without CO_2 Capture (buying credits)

- Variable cost of generation determines dispatch order
- Coal cases (USC steam or IGCC) have lower production cost and dispatch over NGCC cases when CO_2 allowance price < 30 $/ton CO_2
- 50% Biomass co-firing dispatches before coal when CO_2 allowance price <$5/ton CO_2

- Coal steam plants have lower COE than gas when CO_2 allowance price < 20 $/ton CO_2
- Steam plants (USC) lower COE vs. IGCC under all CO_2 allowance price levels
- Subcritical steam plants have lower COE vs. IGCC when CO_2 allowance price < 20 $/ton CO_2
- 50% Biomass co-firing has lower COE than coal when CO_2 allowance price > 15 $/ton CO_2 and has about the same COE as NGCC at 4.5 $/MM-Btu

New Capacity - Future Technologies with CO_2 Capture

The future technologies with CO_2 capture considered include the following:

- NGCC with MEA scrubbing with H-class Gas Turbines
- IGCC with double Selexol with H-class Gas Turbines (with and without an extra train)
- Oxygen fired PC or CFB ultra-supercritical plants (5,075 psig/1,292 F/1,328 F) using cryogenic ASU
- Oxygen fired CMB^{TM} ultra-supercritical plants (5,075 psig/1,292 F/1,328 F) using oxygen transport membrane
- CMB^{TM} carbonate regeneration ultra-supercritical boilers (5,075 psig1,292 F/1,328 F)
- Chemical Looping Combustion ultra-supercritical plants (5,075 psig1,292 F/1,328 F)
- Chemical Looping Gasification with H-class Gas Turbine
- 50% biomass co-firing in PC or CFB ultra-supercritical plants (5,075 psig/1,292 F/1,328 F)

The left side of Figure 11 shows variable cost of generation (fuel + CO_2 allowance price) for future new capacity options with CO_2 capture as a function of the CO_2 allowance price level. The

NGCC option is shown for a range of fuel costs. Figure 11 shows that, even at gas prices as low as 4.0 \$/MM-Btu and all CO_2 allowance price levels investigated, variable cost of generation are high so that the NGCC would only dispatch to very low capacity factors. Additionally, the variable cost of generation for all the coal based technologies (IGCC, PC or CFB, CMB™, CLC, and CLG) are fairly similar and significantly better than NGCC at all CO_2 allowance price levels. Biomass falls in-between coal only and gas.

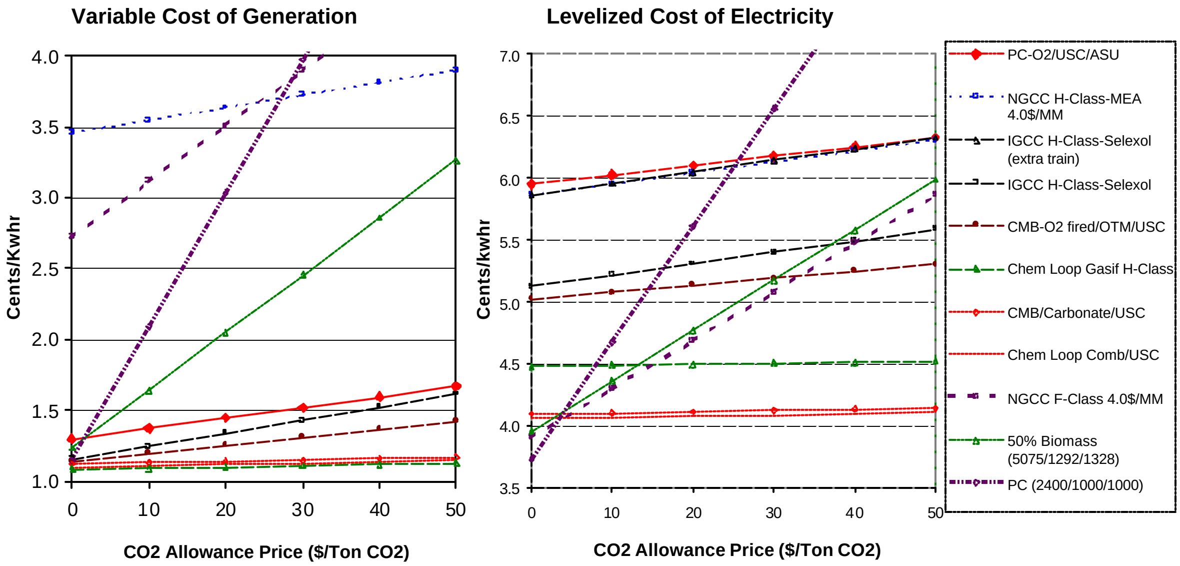

Figure 11: Variable Cost of Generation and Cost of Electricity for Future Technologies with CO_2 Capture (buying credits)

- Variable cost of generation determines dispatch order
- Non-capture baseline case does not dispatch over CO_2 capture technologies when CO_2 allowance price > 0 \$/ton CO_2
- All coal options exhibit similar dispatch economics due to similar efficiencies
- 50% Biomass co-firing does not dispatch before coal with capture for all CO_2 allowance price levels

- Chemical looping and carbonate processes have lowest COE when CO_2 allowance price > 10-20 \$/ton CO_2
- O_2 fired (with cryogenic ASU) and IGCC similar and only beat non-capture PC when CO_2 allowance price > 30 \$/ton CO_2
- O_2 fired (with membranes; OTM) have lower COE than IGCC cases
- 50% Biomass co-firing has lower COE than coal with capture when CO_2 allowance price < 5 \$/ton CO_2 and has lower COE than NGCC with capture at 4.0 \$/MM-Btu at CO_2 allowance price < 50 \$/ton CO_2

The right side of Figure 11 shows the levelized cost of electricity for these technologies with CO_2 capture. The future options of choice with CO_2 capture would be CLC/USC, CMB™/USC/Carbonate technology, or CLG H-class. All three of these technologies are virtually equivalent with respect to variable cost of generation. COE is slightly higher for CLG H-class due to slightly higher investment costs and O&M costs. However given the uncertainty of these costs at this stage of development all three of these three technologies can be considered to be equally favored. These are followed by, CMB™/OTM/USC technology, and IGCC H-class with double Selexol as the next group. Finally, oxygen fired PC or CFB ultra-supercritical with cryogenic ASU, a more conservative option, is higher on variable cost of generation and COE, however much less development would be required for this technology.

Although the investment cost of the NGCC with MEA scrubbing is very low relative to the coal-based technologies, this technology is not of first choice for base load applications, because high gas costs would prevent it from dispatching to high enough capacity factors to justify the investment. The IGCC H-class GT is favorable compared to NGCC H-class with MEA scrubbing or PC ultra-supercritical with cryogenic ASU. Biomass co-firing does not compare favorably to the future coal only options except at extremely low CO_2 allowance price values (< \$5/ton CO_2).

CONCLUSIONS

The Power Generation Industry is experiencing more pressing requirements for competitiveness and environmental sustainability. Equipment Suppliers, like ALSTOM, have a key responsibility to develop new technologies taking into account these new market needs. Given the fact that coal will continue in the future to play an important role in power generation, the increase in the efficiency of coal-fired power plants will remain the first priority for reduced environmental impact, lower CO_2 emissions reduction, and resource savings. Efficiency increase has the lowest cost impact on power generation, saves the resources, and has the potential to satisfy the near term needs.

There is no single, all-encompassing, long-term technological option for greenhouse gas mitigation; rather, there will be a variety of actions that will be needed. These actions encompass a range of technologies with varying technical and economic barriers for industrial implementation. The mitigation of CO_2 will have a significant impact on the cost of producing electricity. Technologies available in the near term for CO_2 capture and sequestration could nearly double the cost to produce electricity. Breakthrough developments are needed to reduce this impact. Some of the long-range technologies being investigated (O_2 firing with Oxygen Transport Membranes, chemical looping, carbonate cycles, and IGCC) show promise and merit further development. These technologies will require field demonstrations to confirm practical considerations such as performance, reliability, robustness, environmental impact and economics. Collaborative efforts, with governmental assistance to facilitate the process, are required. Simultaneously, basic R&D is needed leading to the discovery of completely new and innovative methods for dealing with CO_2 mitigation.

ALSTOM continues to focus its major R&D investments in the demonstration of cost effective and practical power generation systems aimed at both improved efficiency and emissions control (including capture). Through these principles, ALSTOM is committed to the continuous improvement of its technology portfolio in order to meet the present and future needs of its customers.

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